Service Date: August 3, 1984

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of the Application by MONTANA POWER COMPANY for authority to establish increased rates for electric service in the State of Montana.	)	UTILITY DIVISION DOCKET NO. 83.9.67 ORDER NO. 5051d

APPEARANCES

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BEFORE:

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JOHN B. DRISCOLL, Commissioner
HOWARD L. ELLIS, Commissioner
CLYDE JARVIS, Commissioner
DANNY OBERG, Commissioner

COST OF SERVICE

AND

RATE DESIGN

1. Procedural Background. On September 30, 1983, the Montana Power Company (hereafter MPC or the Company) filed with the Commission an application for authority to increase rates for electric utility service in the amount of $96,367,013. The filing was assigned Docket No. 83.9.67.

2. On February 3, 1984 the Company filed an application for interim relief in the amount of $81,305,068. In Interim Order No. 5051 the Company was granted authority to implement, on an interim basis, increased electric rates designed to generate $3,859,009 in additional revenues on an annual basis. As is the Commission's practice with interim rate increases, no consideration of cost-of-service or rate design issues was given and the Company was directed to file revised rate schedules reflecting a uniform percent increase to all rates. This interim increase was subject to rebate should the revenue requirement in the Final Order of this docket be less than the interim. Any rebate would include interest at the then 14.14 percent authorized rate of return on equity.

3. Numerous parties intervened in this docket providing pre-filed, direct, and oral testimony on cost-of-service and rate design issues. The cost-of-service and rate design portion of the hearing began on Tuesday, May 8, 1984 and was completed on Wednesday, May 30, 1984 with the Company's presentation of lighting testimony.

4. Intervenors sponsoring pre-filed testimony on the cost-of-service and rate design portion of this docket included the following parties: the Montana Consumer Counsel (MCC), District XI Human Resource Council [HRC], Champion International Corporation and Conoco, Inc. (jointly referred to as CICO), Stauffer Chemical Company, Exxon and Anaconda Minerals (jointly referred to a SAE), Montana Irrigators, Inc. (hereafter the Irrigators), Montana Legal Services Incorporated on behalf of Low Income Group For Human Treatment (LIGHT) and Butte Community Union (BCU), Ideal Basic Industries (IDEAL), and ASARCO Inc.

5. The Commission notes that this is the second general rate case since 1980 in which the Commission has had opportunity to receive and study electric cost-of-service and rate design testimony for the MPC. The previous case was Phase II of Docket No. 80.4.26. In this docket, the Commission adopted the concept of marginal costs (described fully later in this order) as the basis of rates. The Commission's orders on cost-of-service and rate design out of Docket No. 80.4.2 were only recently implemented (June 5, 1984) due to litigation and extensive judicial review.

6. Organizational Structure. There are two distinct sections in this portion of the order. The first, Cost-Of-Service [COS], deals with the development of unit costs for three general aspects of utility service including energy (KWH), demand (KW), and access (meter) related products. In this initial section the Commission reviews proposed cost studies from the various intervenors, and the MPC, and sets forth the method by which the MPC is to develop cost-based rates.

7. In the second section the Commission discusses how rate design issues, such as inverted and declining block rate structures, service charges and minimum bills will be handled in this docket.

Cost of Service: Methodology

8. Introduction. The initial and single most contested issue in the area of rate design concerns the cost of service methodology. At issue is whether the proper basis of class cost of service and rates is embedded costs or marginal costs. At one end of the spectrum is the embedded cost study sponsored by CICO (E. Odgers Olsen and Mark Lively). The MPC's expert witness (Richard LaCapra) also sponsored an embedded time-differentiated-accounting cost study.

9. At the other end of the spectrum are several marginal cost studies by the MCC (John W. Wilson), the HRC (Thomas Power), and the MPC (Richard LaCapra). These latter studies largely differ by the degree to which they depart from the notion of short-run marginal costs and approach long-run marginal costs.

10. In the balance of the first section on Cost Of Service the Commission contrasts the assumptions underlying embedded and marginal cost studies. Next, the Commission reviews the cost studies submitted in this docket beginning with the embedded cost studies (MPC's and Ernst and Whinney's). Finally, the Commission reviews the marginal cost studies provided by the MPC, HRC, and the MCC.

11. Embedded Versus Marginal Cost Studies: The Assumptions. The Commission would first note that one of the fundamental differences between the competitive marketplace and the regulated marketplace lies in the regulated rate of return constraint. That is, the Commission determines the Company's revenue requirement which only by coincidence would equal the revenues generated by the same company in a competitive market. This constraint is binding and prevents regulators from setting rates to reflect market conditions. That is, the only precise commonality between an embedded and a marginal cost study is the utility's revenue requirement.

12. All cost studies require three fundamental stages of analysis. ln the first, costs are functionalized as generation, transmission, distribution or customer (service) related. In the second, the functionalized costs are classified as energy, demand or customer (access) related. Finally, the classified costs an allocated first to seasons and second to classes.

13. While differences exist between embedded and marginal cost studies at each of the three fundamental stages of analysis, the widest schism is at the first two stages. On the one hand, embedded studies functionalize embedded investment costs and usually classify a large percent of these costs as demand related. Marginal cost studies on the other hand functionalize marginal investment costs and usually classify a relatively larger portion of capital investments as energy related. This difference in turn stems from the fact that marginal energy costs (e.g., gas and oil) usually exceed average energy costs (e.g., coal and water) . This is because on a shortrun basis the MPC dispatches resources on an economic basis to meet loads, beginning with the least costly (e.g., hydro) and ending with the most costly (e.g., the Bird Plant, which burns natural gas or oil) . Another factor includes the difference in how the two cost approaches classify fixed plant capital costs to demand and energy.

14. Another difference between the two cost approaches is a by-product of the marginal cost approach. Only by coincidence would the summation of unit marginal costs (energy, demand and customer) multiplied times the respective test year billing determinants equal the allowed revenue requirement. The difference between the resulting marginal cost revenues and the allowed revenue requirement is resolved, by the marginal cost proponents, by various reconciliation methods. Embedded cost analysts contend that reconciliation destroys the value of marginal cost price signals (see Exh. No. 72, p. 2). This issue is fully discussed later.

COST OF SERVICE: TDAC STUDIES

15. The Ernst and Whinney Cost Study. E. Odgers Olsen (an economist with the Ernst and Whinney Utility Group), testifying on behalf of CICO, sponsored a "time-differentiated average accounting cost (TDAC) study" (Exh. No. 71). Olsen set forth two criteria that any cost study must satisfy prior to being selected for setting rates: (1) "All cost components should be recognized. This means that energy, demand, and customer costs are recognized for all electric utility functions -- generation, transmission, distribution and customer service, and (2) the cost measure should reflect costs that will be actually incurred or can reasonably be expected to be incurred during the time the rates are in effect. This basically limits costs to those that would be included in the revenue requirement. "Olsen stated that his cost study satisfied these two criteria and, in addition, is equitable because ... "ratepayers would only be asked to pay the real cost (emphasis added) of the electric service that is provided to them". [Exh. No. 71, p. 29]

16. In his overview Olsen described the Ernst and Whinney (E&W) TDAC as an approach based on the belief that consumption should be paid for at any point in time based on the cost of providing service at that point in time (see criteria one and two above). To this end the E&W TDAC study features several distinct steps, including the assignment of energy and capacity costs to hours, the summation of these costs, determination of cost periods, and, finally, the allocation of time-differentiated costs to rate classes.

17. Capital costs of the individual units are assigned to the hours when a unit is operating. Costs for all units are summed for each hour to obtain the total costs in an hour that can, in turn, be assigned to classes on the basis of their consumption (peak usage) in the same hour. Transmission costs were allocated on the same basis as generation related capacity costs. Average energy costs were developed using E&W's EBCOST computer model, which assigned costs to hours, and ultimately to rate classes, based on operating costs in an hour and class load in the same hour respectively (see Exh. No. 71 p. 28, and Attachment, pp. 7, 8).

18. The E&W model treats forced outages and off-system sales and purchases by spreading the associated costs and benefits to all hours in the year. By means of sophisticated analysis of variance (anova) statistical tests, Olsen established two seasons of six months each, [April to August being off-peak and the remaining months being on-peak] noting that "...the choice

of costing periods will usually still require some subjective judgments" (Exh. No. 71, Attachment, p. 21). Finally, Olsen noted that, because the above-mentioned energy and capacity costs are those actually experienced in the normalized test year, no reconciliation to the revenue requirement is necessary. (Exh. No. 71, p. 23).

19. The Montana Power Company's TDAC Study. In addition to the E&W TDAC study, MPC also sponsored a TDAC study. There are two distinct theoretical stages to the MPC's TDAC study. The first involves the cost of service analysis leading up to each class' revenue requirement, using LaCapra's TDAC study. The second involves the design of rates (energy, demand and customer) to recover each class' revenue requirement. LaCapra used what is called the Fuel Offset approach for his rate design recommendations. While the MPC combines these two levels into what is called its TDAC study, the Commission will initially deal with the assumptions made in the first stage; the development of unit costs is really an issue of marginal cost pricing and is, therefore, deferred to the portion of this order that discusses the marginal cost studies presented in the case.

20. Like E&W's TDAC study, the MPC's TDAC study is based on capital investments and operating costs incurred during the test year. That is the extent, however, to which the two TDAC studies are similar. Rather than develop short-run average variable and fixed costs, the MPC classified and allocated total costs on the basis of unit operating characteristics and consumption indices respectively. AS with the E&W study, these steps eliminated the need for reconciling the sum of class revenue requirements to the MPC's total electric revenue requirement. Certain details of the MPC's TDAC study follow.

21. Initially, the MPC functionalized costs by production, transmission (separated according to whether the voltage is less than or greater than 100 KV), distribution (primary and secondary) and customer categories. Production-related capital costs were classified to energy based on the operating characteristics of individual units (fuel costs were classified as 100 percent energy-related). The energy share equaled the ratio of average output to peak output; one minus the energy share percent was classified as demand related. As a result, Colstrip units 1, 2 and 3 were classified as 70 percent, 64 percent and 25 percent energy-related, respectively. Hydro units were classified as 90 percent energy related, while the Corette and Bird plants were classified totally to demand.

22. Bulk and local transmission capital costs were classified differently. Bulk transmission (lines larger than 100 KV) was classified on the same basis as the total production classification described above. Local transmission was classified on the basis of a "peak and minimum separation" with the energy portion equaling the percent of minimum system load to peak system load. The demand portion equaled one minus the energy portion. Primary and secondary distribution costs were all classified as demand-related costs.

23. Classified costs were next assigned to seasons. Energy costs were assigned to winter/summer periods based on relative energy use. Production related demand costs were assigned to each month in which a unit was required for service; for example, Colstrip units 1, 2 and 3 were assigned equally to only those months when required output exceeded average output. Hydro was assigned equally to all twelve months. The Corette and Bird plants were assigned to all months when in service. The demand portion of the transmission system, however, was assigned to the peak months only.

24. Seasonally classified costs were next allocated to classes using a number of allocation factors. Energy was allocated on a KWH of usage basis. Production and transmission related demand was allocated on either a single coincident peak (winter) or an average of monthly coincident peaks (summer) basis. Primary and secondary distribution-related demand costs were allocated to classes based on non-coincident peak techniques. Customer costs were allocated to classes on either a per customer or weighted customer basis.

25. The above summarizes the first stage of the MPC's TDAC study. The second stage, as noted earlier, involves how unit marginal costs were developed and used for rate design purposes [i.e., the development of unit rates for demand, energy, and customer], and is discussed later under the topic of marginal cost studies.

26. <u>The Commission's Decision: TDAC Studies</u>. As an initial matter, it should be noted that the theoretical arguments in favor of embedded costs, as well as those in favor of marginal costs are remarkably similar to the arguments that were presented to the Commission in Docket No. 80.4.2 - Phase II, which was upheld on the Montana Supreme Court. <u>Montana Irrigators, Inc. v. Montana Public Service Commission,</u> ____Mont____ , 41 St. Rep. 768 (1984). For the reasons set forth in the following Findings, the Commission rejects the use of embedded costs [time-differentiated-

accounting costs] as the basis of establishing each class' revenue requirement. The Commission's arguments are both generic, applying to both the E&W and MPC TDAC studies, and specific, applying to either MPC's or E&W's TDAC studies.

27. The Commission finds that one objective of ratemaking in a regulatory environment is to encourage efficient resource usage: The rates this Commission sets are the prices consumers will consider when making short run usage and long-run investment decisions. In doing so, it is the Commission's position that, to the degree possible rates should simulate what they would be if a competitive market existed for utility services, although, as pointed out below the assumption of a competitive market is not a necessary condition. This objective finds support by the following two witnesses:

Dr. Wilson:

Q. Moving to another topic, Dr. Wilson, in your opinion is the objective of regulation to simulate a competitive market?

A. That would be one of the objectives.

Q. Is another objective of regulation to remove the opportunity for monopoly profits and price discrimination?

A. That is -- that also can be stated as an objective, although there is obviously a relationship between those two objectives (Tr. p. 4504).

and Dr. Power:

Q. I think you had an earlier discussion about whether regulation was supposed to simulate, to the degree possible, the competitive marketplace. Do you have any professional literature which supports your position?

A. There are two aspects to that position, and I think any textbook in public utility regulation would tend to support that. The two aspects of that position is, one, that the competitive market, when it operates in an efficient way -- I'm not sure when it comes to the discussion of marginal cost one has to turn at all to the competitive market. The situation is quite different. An economist sits back and asks, if one wants to decentralize the economy to operate in an efficient way, what is necessary? Is it necessary to be true about prices? What do we have to make sure about the prices? And the economist is going to

> have to conclude that those prices are going to have to reflect the economy. That's going to be marginal cost.
>
> The economist also will turn and ask, is this likely to happen in a competitive market? And that's a separate conclusion that, yes, it is, and that's why a competitive market can be trusted. That's why we're willing to put up with a competitive market, because that does happen.
>
> So I am not, in this part of the case, in the rate-design part of the case, appealing to a competitive market as the justification for marginal-cost pricing. It's the other way around. Economists who first establish the logic of marginal-cost pricing and then say the commissions who are basing rates on marginal-cost pricing are moving in the direction of encouraging efficient use of energy and competitive markets, because they encourage that sort of pricing, do the same thing (Tr. pp. 4931-4933).

28. The Commission would reiterate a portion of Dr. Power's response. That is, one does not have to rely solely on theoretical notions of competitive markets to defend marginal cost pricing: The efficient use of resources also requires marginal cost pricing. Wilson also made the same point (For example, see the Commission staff's post-hearing written cross to Wilson, No. 43).

29. The connection between marginal cost pricing and the two TDAC studies derives from the methods used to compute class revenue requirement. Both studies allocate to each class a portion of the MPC's embedded capital investment; the resulting allocation, in turn, sets constraints on unit rates.

30. The Commission finds that both TDAC studies fail the test of common sense: rather than asking the question, What does it cost today to generate electricity?, or What will it likely cost tomorrow?, the MPC and E&W TDAC studies answer the question, What has it cost, on average, to generate electricity from roughly the turn of the century to the present?. For example, in a data response to the Commission staff Olsen made clear that an objective of his TDAC study is to inform MPC customers, in the latter part of the twentieth century, of what electricity cost 75 years ago:

> Said differently, all rates should reflect, in part, the relatively lower capital cost of the 1910 hydro unit. (Data response 2D to the Commission staff).

Dr. Olsen also noted:

> I have never claimed that setting rates that reflect the cost of a 1910 hydro plant achieves economic efficiency ("efficient resource allocation"). [ibid]

31. While the MPC's cost allocation in its TDAC differs from the E&W allocation, the starting point is the same: the MPC's historical embedded capital investment. In summary, the Commission's principle concern with the two TDAC studies is that they give customers a price signal that reflects what electric power has cost in the past. Efficient resource usage requires at the very least a signal of what electric power costs today. Specific concerns with each TDAC follow.

32. The E&W TDAC Study. Power and Wilson raised a number of concerns with the E&W TDAC study that are shared by the Commission. The first concern is that the E&W TDAC assumes 90 percent of MPC's production and transmission costs are demand-related, and that transmission costs are allocated in proportion to capacity costs (Exh. No. 40, pp. 17-20). In a data response to the Commission staff Olsen indicated that the E&W model classifies transmission costs "as entirely demand related" (Data Response 9 D) .

33. The Commission finds that this assumption of the E&W TDAC study lacks any common sense. According to the E&W TDAC study nearly all of the MPC resource mix is built to meet peak surges in demand; but, if this were in fact the case, why did not the MPC simply build peaking units in lieu of Colstrip units 1, 2, 3 and 4 and the associated transmission facilities? Coal fired plants like Colstrip units 1 through 4 are universally recognized as being baseload plants, that is, plants designed primarily to serve a utility's general energy requirements, as opposed to meeting occasional peak demands. Wilson specifically noted that one problem with the E&W TDAC study is that it effectively converts Colstrip 3 into a peaking facility (Tr. pp. 4558-4560).

34. The assumption that MPC's capital investments are largely demand related is simply wrong. The MPC clearly indicated that the primary purpose of Colstrip units 1, 2, 3 and 4 is not demand related:

> Q. I believe that you testified this morning in response to a question from Mr. Doubek, and I will certainly give you a chance to paraphrase your answer if you don't agree with my recollection of it, but Mr. Doubek was inquiring about whether and to what extent the coal-fired plants

might be serving the function of supplying peak power, and my understanding of your response is that Colstrip's 1, 2, 3, and 4 were not built only or even primarily for peak. Is that correct?

A. That's a proper characterization, sir. (Tr. pp. 3690, 3691) .

35. Another of Wilson's criticisms, that the Commission concurs with, is the E&W TDAC study's violation of a well known and widely accepted ratemaking objective established by Professor James Bonbright. Specifically, Wilson notes that the use of average instead of marginal costs results in a departure from the objective of "optimum use" (optimum resource use) or what is called the consumer rationing objective (Tr. pp. 4559 and 4588).

36. In a similar vein, the Commission finds yet another inconsistency in the E&W costing approach. One of Olsen's arguments in defense of his TDAC study is that ratepayers will pay the "real cost" of electric service provided to them and that this result satisfies his own two ratemaking criteria (Exh. No. 71, p. 29). In a data response to the Commission staff Olsen defined "real cost" to be ... "the opportunity cost of using resources in one pursuit rather than in the most attractive alternative" (Data Response No. 13 to the Commission staff). From the testimony of Olsen's Colleague Lively, the E&W model would have this Commission tariff industrial energy rates at 0.33¢/kwh and 0.49¢/kwh respectively for the summer and winter months (Exh. No. 70, Exh. MBL-12). But, if one went out into the competitive market to make opportunity sales one would not sell energy (kwh) at such a low rate when opportunity sales prices are higher: That is, someone off-system may be willing to pay 1.5¢/kwh.

37. In the sense that the MPC's opportunity cost of native retail sales revenues is the foregone revenues from "the most attractive alternative" -- off-system opportunity sales --, it is clear to this Commission that the resulting industrial energy rates from the E&W cost study <u>do</u> <u>not</u> reflect the "real cost" of this power to MPC's ratepayers. From the loads and resources section of this order it is clear that for year 1983 (actual) the price for out of state sales averaged 1.47¢/kwh. This low a value for out of state opportunity sales, in turn, reflects the regional surplus of power. Projected out of state sales rates for 1985 are higher yet at 3.094/kwh: Therefore, a very substantial difference exists between E&W's proposed industrial energy rates and the value of the same product in terms

of out of state sales -- the opportunity cost. The comparison clearly shows that the E&W cost study would not result in efficient resource allocation.

38. These rates would be charged for guaranteed firm power. By contrast, the 1983 price for non-firm power sold by MPC is 1.47¢/kwh. That comparison alone strongly suggests that these proposed rates are absurdly low.

39. In addition to the above problems with the E&W TDAC study, the Commission would note the opinions of two eminent economists. One, Nobel Laureate Mr. Kenneth Arrow, stated the following with regard to using embedded cost studies[1]:

> He states, "In sum, therefore, one can say that price-setting on the basis of fully distributed costs is economic nonsense and has no more place in regulated industries than it does in the unregulated sector. If the goal is economic efficiency, pricing by a multi-product regulated firm should follow the Ramsey principles." (Tr. p. 4037).

40. The other, Mr. Alfred Kahn, holds a similar viewpoint:

> Mr. Kahn states, "It is a familiar and elementary proposition in economics that sunk costs (embedded costs) are and should be irrelevant to short-run pricing and output decisions. " (Tr. p. 4038).

41. There is another apparent inconsistency in the E&W testimony. On one hand Olsen and Lively argue for using an embedded TDAC for cost of service and rate design purposes. On the other hand, Lively seems to support the positions of Arrow and Kahn:

Q. How would you modify the penalty clause into an interruptible clause?

A. ... "One approach would be to use avoided costs. " (Exh . No. 70, p. 36) .

42. Lively's colleague, Olsen, equates avoided costs to incremental costs:

Q. In doing those studies, how did you define "avoided cost"?

[1] Ramsey pricing as used by economists argues for setting prices that deviate from costs in inverse proportion to the elasticity or demand for a group of products or services. For a practical example the reader should refer to the Commission staff's cross-examination of Haler (Tr. p. 5155). The concept is attributed to a 1927 journal article by Frank Ramsey.

A. We calculated avoided cost using what's called the CUB method, the committed-unit basis, and it's an examination of the expansion plan of the utility. It's not marginal cost. What we're really looking for is the cost that could be avoided, and the way to look at those avoided costs is to look at what's -- look first to the forecast, look second at the expansion plan, and look third at an adequate supply of capacity to meet the forecasted needs, and so that's really the steps that we have done in Texas and other places where we've done avoided-cost studies, and we look at an actual unit that's in the plan that could be avoided.

Q. Would you contrast that to your definition of "marginal cost" ?

A. It's considerably different. There are two definitions of "marginal cost" that are in the economics literature.
. .
So there is a short-run marginal cost; there is a long-run marginal cost. The allocative efficiency arguments tie to long-run marginal cost, and it's an abstract definition that's fictitious.

Q. Could you contrast your avoided-cost concept - -

A. Yes.

Q. -- with the concept of marginal costs?

A. Yes. When we're looking at avoided costs, we're looking at the cost that the utility, in fact, could avoid, and that has to look at a real unit in the expansion plan.

Q. An incremental unit?

A. An incremental unit in the expansion plan. It's not a long-run marginal cost or a short-run marginal cost; it's an incremental cost, that's right. (Tr. pp. 5094-5096).

43. In summary, according to Olsen, avoided costs equal incremental costs and incremental costs are in turn a function of <u>an incremental unit in the expansion plan</u>. Contrary to Olsen's opinion many economists would consider this an adequate definition of marginal costs.

44. E&W's own expert witness Lively equates marginal costs and incremental costs to avoided costs:

Q. Mr. Lively, to your way of thinking, are avoided costs and marginal costs the same thing?

A. There are differences in that avoided costs are typically considered to be incremental or decremental in that they exist over a wide-range show for a discrete change in load. Marginal costs are typically thought of as a derivative or as a -- For a small, instantaneous -- or a small, very almost indiscrete change, the marginal cost would be that calculation.

Q. Are incremental rates generally a proxy for marginal costs?

A. There should be small differences. There (sic) would be good proxies. (Tr. pp. 5060, 5061).

45. The Commission finds the above testimony by E&W's two expert witnesses logically contradicts the same witnesses' own testimony on cost of service and rate design, since, on the retail side, those witnesses argue that short-run average costs (historic costs) are not only appropriate but the only relevant price signal.

46. When a utility is strapped to meet loads with its own resources, an interruptible rate that features a marginal cost (avoided cost) price signal -- based on an avoidable unit (Colstrip 3 for example) -- becomes important. But an avoidable unit or, for example, an emergency purchase to satisfy loads, is just another resource in the dispatch order. At any given hour the most expensive resource in the dispatch is the resource whose costs could be avoided if load was decreased by a small amount.

47. If avoided costs are appropriate price signals for customers who allow the utility to avoid the construction of future units or emergency purchases, then the same cost is an appropriate signal to customers who choose to consume and cause the utility to incur marginal costs.

48. Lively's own testimony supports this position:

Q. In talking generally about interruptible rates on page 36, you say at the top of the page, "One approach would be to use avoided cost". I assume by saying that you think that's a valid approach.

> A. When you have a rate-decisions pattern that is trying to affect the actions, directly affect the actions, and there's an immediate tradeoff between what the consumer's going to do for that marginal consumption, then avoided cost makes sense for either an interruptible rate or for buying power from a qualifying facility or from any other person who wants to generate electricity, whether it's a qualifying facility or not. (Tr. pp. 5055, 5056).

49. To argue that avoided costs are only appropriate for interruptible rate design purposes and not retail electric rate design is illogical. In both cases the avoidable cost is the incremental cost which in turn is a function of an avoidable unit in the resource plan.

50. The MPC TDAC Study. The Commission's findings with regard to MPC's TDAC study sponsored by LaCapra follow. In addition to the backwards-looking perspective that LaCapra's TDAC study takes, the Commission finds that the classification of costs between demand and energy is arbitrary. Two types of classification are clearly questionable. First, Colstrip 3 capital costs were classified as 75 percent demand related, the balance energy related, as described by LaCapra:

> Q. Mr. LaCapra, you've been asked about the capacity factor you used for Colstrip 3, but I would like to pursue that just a little bit longer. In response to MPC Data Request 16-19(c), you did state that you used a capacity factor of 25 percent.
>
> Where did you derive the 25 percent?
>
> A. The 25 percent was derived from the PROMOD output simulating the normalized 1982 year as if Colstrip had been available for the full year. And the 25 percent value is typical of that year. Basically, the infancy of the plant moved into a period which it predominantly was not in service. This was the nature of the normalization. And that is the reason why it came out low.
>
> And if I hadn't made it clear, the position I was taking on that capacity factor was that I have no objection as an analyst to using normalized capacity factors in the development of the TDAC. I used actual actual-year normalized experience which showed the range of capacity factors based on this simulation.
>
> As a practical matter, since I believe it is ultimately to be part of this docket, was the submission of our FERC filing which looked at a period, too, into '84, showed the Colstrip capacity factor at somewhere in the 52, 53 percent range, close to where it would be in steady state.

> The classification, I believe, can be properly done looking at the actual test year. In certain cases, certain companies would adopt a normalized capacity factor to, say, look at it over the life and classify it that way. Both approaches are valid. The one I submitted is an actual simulation of a test year as opposed to normalized operating conditions of the unit. I believe both are valid approaches, and what is submitted was one of those two valid approaches. (Tr. pp. 4310-4312)

51. It is evident from the above Finding that a range of Colstrip 3 related capacity factors of 25 percent to 53 percent exist. On the other hand, a 60 percent capacity factor for Colstrip 3 was used for revenue requirements purposes (Tr. p. 4312). The ceiling capacity factor may be higher yet: In a Company data response to the HRC it is clear a 75 percent capacity factor may be relevant (Data Response No. HRC 1-54).

52. As evident from the following exchange a similar problem is associated with MPC's peak/energy power exchange agreement with BPA:

> Q. Are you aware of the peak energy exchange agreement between the Montana Power Company and BPA?
>
> A. Yes, I am.
>
> Q. Well, under this agreement, Montana Power Company is required to return all of the energy received from BPA during the peak hours, plus an additional amount, are they not, or is it not?
>
> A. Yes, it must return the energy which it uses at peak, plus supply a continuous 28 average megawatts to BPA.
>
> Q. Twenty-eight average megawatts?
>
> A. That's correct.
>
> Q. Did the agreement then cause the generating resources to achieve a higher load factor?
>
> A. Some, yes.
>
> Q. Okay. Should the costs of this peak energy exchange agreement be considered demand related or energy related?

A. Well, as I stated in my rebuttal, this is one of the areas that has an argument on both sides. The stronger argument is that it would be primarily energy related in that while it is used at high load times, its basic cost is measured in terms of energy. Its exchange is paid for an interchange on the basis of energy. So the fact that it is a hydro exchange, which is actually being transacted in energy, gives some weight to the fact that it should be considered as an energy transaction. (Tr. pp. 3532-3533).

53. The above exchanges clearly indicate to the Commission that the MPC classification of costs is fraught with subtle judgements by LaCapra (Tr. p. 3895): Should Colstrip 3 be allocated 75 percent energy related or demand related? Should PROMOD be re-run with a new assumed capacity factor for Colstrip 3 and new capacity factors computed for the balance of MPC's thermal resources? Or, should long-run "steady state" capacity factors be used for each thermal resource? Regarding MPC's peak/energy exchange with BPA, can one know with certainty whether the energy returned to BPA came from Colstrip 3 or the Company's hydro resources?

54. In summary the Commission finds, for the above reasons, that the E&W and MPC TDAC studies are ill-suited for purposes of developing class revenue responsibilities. The E&W TDAC study is also ill-suited for purposes of developing unit costs for energy and demand. The Commission further notes that there appears to be no apparent means of correcting these studies to make them acceptable to this Commission for purposes of retail ratemaking.

COST OF SERVICE: MARGINAL COST STUDIES

55. The MPC and intervenors in this docket submitted a combined total of six marginal cost studies. The MPC's three separate studies included the fuel offset, base peak and peaker. The MPC also provided a peaker study. Stauffer, Anaconda and Exxon (SAE) suggested a cost approach referred to as the "alternate method."

56. The commonality and focus of the above studies is the calculation of generation related demand (kw) and energy (kwh) costs The MPC also computed marginal transmission, distribution, and access (customer) related unit costs; the HRC employed MPC's estimates of these marginal costs. The MCC adopted the MPC's embedded distribution and customer-related cost estimates .

57. In the following findings, the Commission contrasts certain assumptions underlying the calculation of generation-related demand and energy unit costs. The reasons for this focus are twofold. First, it is with generation-related costs that the controversy of short-run versus long-run marginal costs arises. Secondly, as noted by Wilson, the objection of efficient resource allocation is achieved by correctly pricing generation related demand and energy:

> Q. IS IT EQUALLY IMPORTANT TO DETERMINE THE MARGINAL COST FOR EACH OF THESE FUNCTIONAL COMPONENTS ON THE MPC SYSTEM?
>
> A. No. The determination of marginal costs should focus primarily on the bulk power production function, which includes the provision of capacity to meet peak demand and the production of energy. It is in the performance of these functions that the most important marginal cost variations occur. Also, it is generally only at the bulk power level that marginal cost pricing serves to attain the rate design objectives of <u>efficiency</u>, <u>conservation</u> and <u>equity</u>. (Exh. No. 63. p. 50).

58. Marginal energy costs are computed by means of the Company's PROMOD computer model and include amounts for fuel inventory, running costs and working capital requirements.

59. MPC calculates generation-related marginal demand costs on the basis of the Company's resource plan. LaCapra described this process as follows:

> The present value of the stream of revenue requirements for each individual resource is stated in terms of its year in service. From its year in service, an escalating stream of annual revenue requirements in current dollars is computed through the life of the resource plan (the planning horizon). This represents the current dollar payment that would be incurred if each of these resources were installed as planned.
>
> Since resources are installed on an economic basis, each resource should provide some offsets or savings in variable and operational costs. To measure any variable cost savings associated with incurring the fixed charges specified in the resource plan, a second scenario considering no additional resources is computed through the same time period. While the fixed charges of the no additional resource plan are apt to be lower, variable charges, because of the use of less efficient machines, and the reduced opportunity for off system sales, are likely to be higher.
>
> The marginal capacity cost is thus determined by considering each year in the resource plan and computing the current dollar

> stream of annual revenue requirements, less the current dollar stream of fuel offsets and increased system sales. The fuel offset is the difference between the variable production charges in the resource and no additional resource plan. The off system sales increase is the opportunity sale occasioned by having the resource available, less the cost of producing the off system opportunity sale. (Exh. No. 2, pp. RLC - 6, 7).

60. MPC's Peaker. The MPC's Peaker study combines short-run marginal costs for energy with long-run marginal generation-related demand costs. Energy costs are identical to those developed in the Fuel Offset study. Generation related demand costs are based on the hypothetical costs of a combustion turbine (CT). (See Exh. No. RLC-6).

61. MPC's Base-Peak. The Base-Peak cost study as computed by LaCapra provides long-run marginal cost estimates for generation-related demand and energy.

62. The unit demand cost estimate combines the cost of the CT (from the Peaker study) with what is called a fuel penalty. The fuel penalty adder reflects the capacity related fuel costs of a combustion turbine less the energy related baseload capacity costs (see Exh. RLC-7).

63. The baseload capital costs in LaCapra's study, equal the de-escalated total capital costs of the MPC resource plan divided by the total KW capacity in the plan.

64. The Montana Consumer Counsel's Peaker Study. Wilson's peaker study combined marginal energy costs and marginal generation-related demand costs with the MPC's embedded distribution and customer cost estimates

65. Wilson's results for generation-related demand and energy unit costs are similar to LaCapra's. Wilson's energy costs differ from LaCapra's due in part to Wilson's use of 1986 costs compared to LaCapra's use of a five year average in current dollars. Wilson's generation related unit demand cost estimate (1986 dollars) is slightly lower than LaCapra's (1985 dollars), due to Wilson's exclusion of general and common, administrative and general and working capital loaders. The difference is slight, however.

66. Human Resource Council's Base-Peak Study. Power sponsored a Base-Peak study that significantly differs from the Base-Peak study provided by LaCapra. First, Power initially argued that the Salem Plant, the single baseload coal-fired generating plant in the MPC's resource plan, is the relevant baseload resource for his calculation (Exh. No. 39, p. 40). [By contrast, LaCapra uses

all resources in the Company's resource plan.] Next, Power argues for proxying the costs of the Salem plant with the costs of Colstrip 3, noting that "... the costs of Colstrip 3 would understate the real cost of future increments of supply the size of Salem" (ibid., p. 45). Power also argued that Colstrip 3 costs are actual, not engineering estimates, and as a result not subject to forecasting errors and other factual uncertainties (ibid., p. 47).

67. The difference described in the above finding is the major difference between Power's and LaCapra's Base-Peak approach. A minor difference is that Power holds the fuel penalty to be energy and not demand related and consequently places this cost on energy. (Tr. p. 4852). Other differences exist and are discussed below.

68. Stauffer, Anaconda and Exxon's "Alternate Method". Schoenbeck, on behalf of SAE, stated that an appropriate cost study approach is the "... alternate method, that is being considered by various parties in the Northwest". (Exh. No. 56, pp. 20-21). Shoenbeck further described this approach:

> However, an alternate method, that is being considered by various parties in the Northwest, is to adopt a single classification split between demand and energy based on incremental costs which would be applied to all production-related revenue requirement items within embedded cost studies .
>
> The classification split can be determined by applying the incremental cost of capacity to the system peak and the incremental cost of energy to the energy load. The calculation would be as follows:

Recommended Classification Of Production Costs

	Load	Cost	Incremental Revenue (000)	Resulting Classification
Capacity (MW)	1196.0	$ 85	$101,660	57.8%
Energy (MWH)				
Winter	2,423,183	13.85	31,623	
Summer	4,279,706	9.94	42,540	

Energy Total	6,702,889	$ 74,163	42.2%
Total		$175,823	100.0%

> This calculation, which uses a corrected January peak and constant dollar marginal energy costs, results in classifying 57.8% of all production costs to demand and 42.2% to energy on the Montana Power system. (ibid, pp. 20, 21).

69. It should be noted that unit marginal costs in Schoenbeck's classification include short-run marginal energy costs and long-run marginal demand (generation related) costs. The former costs are from MPC's PROMOD model. The latter are from LaCapra's Fuel Offset study. Further, it should

be noted that Schoenbeck is classifying embedded -- not marginal -- production costs.

70. The Commission's Decision: Marginal Cost Studies. For the reasons set forth in the following findings, the Commission rejects all of the above marginal cost studies except Power's Base-Peak approach. The Commission will first provide its reasons for rejecting those studies relying on short-run marginal energy costs (LaCapra's Fuel Offset and Peaker, Schoenbeck's alternate method and Wilson's Peaker). This will be followed by specific problems the Commission has with LaCapra's Fuel Offset and Schoenbeck's alternate method. In an optional situation where loads and resources are in equilibrium, the marginal cost studies generate similar results. System lambda will reflect the opportunity cost of energy-related base load capital expansion. In this docket, the system lambda results from a PROMOD execution which includes Colstrip 3 and 4. Because of this the results from the methods diverge dramatically.

71. The Commission finds any cost study that incorporates the MPC's short-run marginal energy costs [as generated by the Company's PROMOD computer model] as the basis of a generation related energy price signal should not be used in this docket. This finding simply follows from the fact that the MPC system has surplus generating capacity; this surplus has driven the short-run marginal cost of energy to an unreasonably low level that is only a temporary aberration. Therefore, prices based on those costs would give incorrect price signals for the longer term.

72. In addition to the current short-run marginal energy costs being unrealistically low on an absolute basis these costs also appear low on a relative basis. For example, in Phase II of Docket No. 80.4.2, the MPC's expert witness, Bruce Ambrose, provided marginal running costs for

the winter and summer months (1980 dollars). The average running cost for years 1985-1990 and for the winter and summer months equaled 20.69 and 10.64 mills/kwh respectively (Ambrose's schedule 1, p. 2). If adjusted (escalated) to 1985 dollars to be compatible with LaCapra's analysis in this docket, one would find a stark contrast: LaCapra's average of 1985-1990 marginal energy costs in this docket equal 14.42 and 10.97 mills/kwh. These averages, however, are not in constant 1985 dollars, but rather in higher average current dollars (see Exh. No. 73, p. 6); that is, these costs should be discounted back to 1985 dollars and then averaged.

73. Therefore, to tariff LaCapra's short-run marginal energy costs would give customers the signal of declining costs, since current rates are higher than those proposed. This is exactly the wrong price signal during the present time when the Company is planning substantial additions of baseload generating capacity (Colstrip 3 and 4) and is further planning a major coal-fired baseload generating plant -- the Salem plant in 1996. The Company's own testimony is that the Colstrip units are not primarily peakload related (Tr. pp. 3690, 3691); but, if they are not peakload related then they must be baseload related, that is, energy related.

74. The Bonneville Power Administration has also emphasized that energy costs are rising and not declining:

> The cost relationship between capacity and energy is changing as Bonneville purchases the output of new thermal plants. By comparing the results of the average cost of service analysis with those of the long run incremental cost analysis, this changing relationship is evident. These studies show that though all costs are increasing, the costs of supplying energy are increasing at a faster rate than the costs of supplying new capacity ... (BPA, Summary Rate Design Study, February, 1981) (Exh. No. 39, p. 59).

75. It is obvious, therefore that the current short-run marginal energy costs from the Company's PROMOD model are aberrationally low, reflective of the MPC's current surplus of power on that basis, and do not reflect the reality that, in absolute terms, energy costs are rising. The Commission rejects the use of those cost studies relying on short-run costs. The Commission notes that Power indicated that the Company's excess capacity should be removed prior to using the energy costs from the PROMOD model (Tr. pp. 4617-4619, and Tr. pp. 5008-5010). This approach would

correct the problem of artificially low energy prices; however, there are substantial and complex problems that precluded this approach.

76. Like E&W's proposed industrial energy rates, those marginal energy costs proposed by LaCapra fail the test of reasonableness. From LaCapra's testimony short-run marginal energy costs in 1985 dollars range from 1.125¢/kwh/winter to 0.964¢/kwh/summer (Exh. No. 2, Exh. No. RLC-4, p. 2). As noted earlier in the companion order on loads and resources (Order No. 5051c), the Pacific Power and Light energy rate to Black Hills Power and Light is initially on the order of 37 mills/kwh, a rate three times LaCapra's recommendation The Commission finds that this contract rate is a very good estimate of the current market value of energy in the region. Duffield's testimony also indicates that the market value of power is in the four cent range:

> . . . if Montana Power separated off those 3 and 4, the going price for marginal power's going to be more like around 4 cents, because they're going to be using conservation, they're going to be using firm purchases, they're going to be firming up that median hydro by using Bird and maybe putting in another combustion turbine. There's no way in the world that they're going to be paying for 12 cent power when we're talking about 3, 4 cent long term firm purchases in the region. (Tr. pp. 2799-2800).

77. At three points in his testimony Power also emphasized the Pacific Northwest Power Planning Council's position on the use of regional marginal costs as an "acid test":

> The primary cost test . . . of the appropriateness of a particular rate design should be regional marginal cost . . . (Exh. No. 39, pp. 102, 119, 147).

Given the above, it should be clear that the MPC's short-run, marginal energy costs fail relevant tests for reasonableness.

78. The Commission would note it is not abandoning short-run marginal energy costs as relevant price signals; rather, the Commission finds the resulting short-run costs, in this docket only, to be undesirable because of the fact the PROMOD execution includes excess capacity -- Colstrip 3.

79. Aside from its incorporation of PROMOD's marginal energy costs, the Commission finds that there are substantial problems with the Company's Fuel Offset study that render it useless in the current proceeding.

80. Some of these problems can be understood by a comparison of LaCapra's Exhibit No. RLC-5, page 2 of 2, to the revisions set forth in MPC's Exhibit No.'s 46 and 47. First, LaCapra initially includes off-system sales (Exh. RLC-5) in his calculation of the cost per kw of generation-related demand; on Exh. No.'s 46 and 47 he excludes off-system sales. Should off-system sales be included in his analysis or not? LaCapra appears to say "maybe", Dr. Power says "yes" (Tr. p. 4933). The Commission is, therefore, unable to determine the correct answer from the evidence presented.

81. Secondly, there is no apparent analytic connection between off-system sales and LaCapra's use of years 1993 through 2005. If off-system sales are included in his fuel offset cost study, Mr. LaCapra divides the discounted (and partially de-escalated) present value of the resource plan by 421.2 MW Exh. RLC-5, p. 2); if, however, off-system sales are out, Mr. LaCapra divides by 5473 MW (13 times 421.2). The Commission finds no rational analytic connection between these two variables.

82. Another curious judgment by LaCapra was his decision to pick out 1993 as a significant year in the resource plan. This year is the first year that a resource in the Company's plan comes on line The significance of this year to LaCapra is that, in arriving at the present value of the resource plan, one de-escalates costs beyond year 1993 back to 1993, and then one discounts costs from 1993 back to 1985. (Exh. No.'s 46 and 47). This mix of techniques to determine the present value of future costs does not appear to have any practical or theoretic support. In comparison, LaCapra de-escalated plant costs in the Company's base-peak study (Exh. No. RLC-7, p. 2).

83. In addition to these two different approaches for determining present value is still a third. Hafer noted that LaCapra neither discounted nor de-escalated his marginal energy costs, but rather computed a five year average in current dollars (see Exh. No. 73, p. 6).

84. The Commission also is troubled by the inconsistency in resource plans used by MPC's witnesses. On one hand, Gregg's testimony indicates Kerr upgrades 1 and 2 occur in 2003 or beyond (Exh. No. DBG 2 pp. 1 and 2). LaCapra, on the other hand, has the Kerr upgrades on-line

around 1993 or 1994. A similar problem exists with the Thompson Falls upgrade. No explanation is offered for this difference in on-line dates for three of the Company's seven future resources.

85. Aside from the distorted marginal energy cost signal used in the fuel offset cost study, the Commission finds these problems significant enough to reject the use of the study.

86. The Commission finds Schoenbeck's proposal equally unsatisfactory. His use of LaCapra's generation-related costs results in the same criticisms applicable to the fuel-offset being applicable to his "alternate method." Schoenbeck's proposal also suffers from the problems the Commission has also with embedded cost studies.

87. It should also be noted that Schoenbeck's "alternate method" is not in as widespread use as his testimony would lead the reader to believe. In a data response to the Commission staff he noted just one utility that uses his "alternate approach" (Data Response No. 33A to the Commission staff). The Commission notes also that that utility, Pacific Power and Light, employs the equivalent of Power's Base-Peak approach in the state of Montana and has done so in its most recent electric docket (Docket No. 83.5.36).

The Base-Peak Cost of Service Approach

88. The Commission endorses the Base-Peak approach as the approach that should be used for cost of service and rate design purposes in this docket. There are a number of revisions, however, that must be made to the Base-Peak approach provided by Power and accepted by this Commission. These revisions are as follows:

89. Baseload Capital Cost. The Commission finds that Colstrip 3 costs should be used as the baseload capital costs in the Base-Peak approach for the reasons outlined by Power. Certain of the MPC's revisions of Power's Table G are accepted (see Exh. No. 67) as the basis for determining those costs .

90. The cost per KW of Colstrip 3, therefore, equals $1358/kw (1985 dollars). The Commission finds, based on this record, that no further AFUDC adjustment is necessary. It may be however, that a more precise representation of the economic cost of Colstrip 3 involves discounting[2]

[2]Discounting, as opposed to de-escalating a cost, involves the reduction in a cost by use of a discount rate. The discount rate that would be used, in the absence of a social discount rate, would reflect the Company's weighted cost of capital. De-escalation involves the reduction in a

each year's (approximately 1973-1985) cash outflow plus AFUDC back to year 1973. This resulting 1973 present value figure would then be escalated with the most recent Handy Whitman indices, forward to year 1985; another approach would ignore AFUDC entirely and simply escalate each year's cash outflow up to year 1985. Such an adjustment will have to be made in the Company's next general retail electric case. Based on the record the Commission finds the $1358/kw figure reasonable.

91. The appropriate carrying charge is a real carrying charge of 10.58 percent as computed by the MPC [note the averaging in the below finding]. A real carrying charge, as opposed to a nominal, is supported by Power, Wilson, Hafer and LaCapra.

92. There is an issue of whether an end-of-year or beginning-of-year carrying charge should be used (Tr. pp. 4903 and 4325). In the absence of precise resolution to this problem the Commission finds that an average of an end and beginning-of-period carrying charge should be used.

93. Also at issue in the calculation of a carrying charge is whether a tax or service life should be used. Power and LaCapra supported a tax life. The MPC Reply Brief supports a service life calculation. Wilson also supports a service life approach [see the Commission staff's post-hearing written cross-examination to Wilson, No. 23]. The Commission finds that a service life approach should be used. This is the same approach used by PP&L in its Black Hills Power and Light contract as well as in this Commission's electric avoided cost dockets. The vagaries of the tax laws make a tax life approach an unstable one. Further, as indicated by the MPC in its Reply Brief, capital recovery occurs over the book or service life and not the tax life. It is also the case that a resource will produce power over its service life and not its tax life.

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cost by use of an escalation rate; the escalation rate in turn is the rate of inflation for a baseload coal-fired generating plant. Handy Whitman indices for the Plateau Region are the appropriate escalation rates for either de-escalating or escalating a capital cost.

94. Another issue involves the use of a six percent or seven percent escalation rate in the carrying charge calculation. A six percent rate should be used, as suggested by Power and LaCapra (Tr. 4964 and MPC Data Response to the Commission staff No. 13-34B).

95. The Commission finds appropriate LaCapra's corrected General and Common loader of 1.0679 as indicated on Exh. No. 67.

96. There exists an issue of whether fixed and variable O&M should be included on a first year or levelized basis. The Commission finds that, in order to be consistent with the first year cost estimate associated with the use of a real carrying charge, first year estimates of O&M must also be used .

97. Also at issue is the value of the plant (capacity) factor associated with Colstrip 3. Power apparently used a 65 percent factor. The MPC on the other hand apparently used a 75 percent factor. (MPC Data Response No. HRC 54). The Commission finds 70 percent appropriate. This is the same value used in the electric avoided cost dockets and also is middle ground between the MPC and HRC positions.

98. A final issue in the carrying charge calculation regards the appropriate discount rate. The choices are a Colstrip 3 specific (12.56 percent) or a utility wide discount rate (13.74 percent). The Company should use the former Colstrip 3 specific rate with Colstrip 3 capital costs.

99. With regard to other capital related costs including, combustion turbine and transmission costs, the Company's carrying charge calculations must be consistent with the above findings, that is, a real carrying charge computed on the basis of an average end and beginning-of-year calculation using service life. All costs should be in 1985 dollars. The discount rate for non-Colstrip 3 capital costs should equal 13.74 percent.

100. <u>Combustion Turbine Capital Costs</u>. The cost of a combustion turbine (CT) in the Base-Peak approach is used for two purposes. The first is to compute the energy related portion of baseload capital costs; the second is to estimate generation related demand costs.

101. The Commission finds that the cost per KW of generation-related demand equals $80.72/kw per year. This cost includes the $66.22/kw of a CT plus a fuel penalty of $14.50/kw per year. The running costs of a CT over and above the energy-related cost of Colstrip 3 appear to be

capacity -- demand -- related; that is the fuel costs associated with running a CT are incurred to meet peak demands and not additional energy demands

102. Transmission-Related Energy and Demand Costs. At issue here are three conceptually different types of transmission costs including (1) baseload; (2) peakload (combustion turbine); and (3) network or reliability-related costs. Each is addressed in turn.

103. Initially at issue is whether any portion of the 500 KV line associated with Colstrip 3 and 4 should be included in the base-peak calculation as Power suggests (Exh. No. 39, Table G and Tr. p. 4944). Power's Table G included 75 percent of the total cost of the 500 KV line. Power also included the 230 KV transfers.

104. The MPC's revision of Power's Table G makes several adjustments to the above calculation. The MPC includes only 50 percent of the cost of the 500 KV line and eliminates the 230 KV transfers. The MPC further classifies a fraction of 50 percent of the 500 KV line as demand related; this fraction equals the annualized cost of the CT ($80.72) divided by the annualized cost of Colstrip 3 ($182.25). The balance of the cost of Colstrip 3 is classified as energy related.

105. The Commission finds merit in Power's decision to include a portion of the cost of the 500 KV line with the cost of Colstrip 3; however, only 50 percent should be included as proposed by the MPC in Exhibit No. 67. The Commission agrees with the MPC's exclusion of the 230 KV transfers: the 500 KV lines are truly incremental construction costs. The 230 KV transfers are not.

106. The Commission does not find the MPC's classification of the 500 KV line costs appropriate. The costs of the 500 KV line, as stated by Power, are part of the generation facility. The correct classification of the 500 KV line costs is as Power proposed (Tr. 4644). While not perfect substitutes, the MPC could have built Colstrip 3 closer to load centers and incurred higher transportation costs while avoiding certain transmission costs .

107. The Company must add to the resulting annualized cost of Colstrip 3 the annualized cost of 50 percent of the 500 KV line ($27.60/kw per year, Exh. No. 67, p. 2 of 5, Line 12).

108. The second type of transmission related cost is associated with the cost of the CT. The Commission finds that it is appropriate to include the $233,348 cost of connecting a CT to the grid system with the cost of the CT of $13,159,959 (see the MCC's response to Commission staff

Data Request No. PSC JW-17). From the Company's statement L (Appendix A, p. 2), and Wilson's above-cited data response, it is clear that the $66.22 cost for the CT already includes the transmission component.

109. The third type of transmission costs involve the marginal costs associated with maintaining system reliability. LaCapra's Base-Peak study (Exh. RLC-7) included marginal transmission costs for demand ($46.16/kw) and energy ($4.62/kw). On another exhibit LaCapra shows a marginal cost per kw of transmission-related demand equal to $46.19/kw (<u>see</u> pp. RLC-9 and 10 of MPC Exh. No. 2 for a description of this calculation).

110. In his Base-Peak cost study Power adopted LaCapra's costs from Exhibit RLC-7. Rather then apply the costs as classified by LaCapra. Power makes an arbitrary 50/50 classification of the summation ($46.16 plus $4.62).

111. The Commission finds merit in LaCapra's classification of marginal transmission costs as reported on Exhibit RLC-7. Power's 50/50 split is arbitrary and unnecessary. The $4.62/kw energy-related transmission should be converted to an energy rate (¢/kwh) per Power's calculation (multiply by 1230.7 peak MW and divide by the product of 778 average MW and 8760).

112. <u>Marginal Distribution Costs</u>. LaCapra computed marginal distribution related demand costs for primary and secondary voltage levels. The technique used was similar to that for computing marginal transmission (Tr. pp. 4293-4294) costs. The resulting costs for primary and secondary voltage equal $75.32/kw and $20.97/kw. Power also adopted these costs in his cost study. As previously discussed, the Commission finds the marginal cost approach preferable to the embedded. The issue of allocating these costs to classes is discussed in later findings.

113. Hafer proposed two changes to LaCapra's calculation of loaders used in the development of marginal transmission and distribution costs. First, Hafer contends errors exist in the development of general and common loaders for production, transmission and distribution plant. Essentially LaCapra weighted the five year average general and common loaders by a combination of (1) the respective percents of each of three functionalized components (production, transmission and distribution), and (2) a multiplier of "3" reflective of the number of functional components. Hafer argues that multiplying by "3" is erroneous and proposed simple (corrected) loaders of O.0281 and 0.02859 respectively for each functionalized component.

114. The Commission finds Hafer's analysis correct. LaCapra's analysis assumes every dollar increase in total plant, due, for instance, to just one function (e.g., production) requires a three-fold increase in general and common costs. But this would only be the case if there was a dollar increase in costs for each of the three functions.

115. Second, Hafer also criticized LaCapra's use of the loaders. LaCapra multiplies one plus his loaders times plant costs. Hafer states that the unloaded plant (total plant less general and common) should be divided by one minus the loader.

116. The Commission also finds this correction appropriate. In the hearing, LaCapra acknowledged this correction (Tr. p. 4293).

117. Marginal Customer Costs. LaCapra developed marginal customer costs which were in turn adopted, with suggested changes, by Power. Then costs were developed for each class by assigning costs on a per customer and weighted customer basis (Tr. p. 4281). The results are as follows:

Marginal Customer Costs

CLASS	ANNUAL COST	MONTHLY COST
Residential	$ 37.63	$ 3.13
General Electric	59.89	4.99
Electric Church	36.78	3.07
Irrigation	59.32	4.94
Industrial Customer	1,190.78	99.18
Missiles	123.12	10.26
Lighting	1,637.02	136.42
REC	727.61	60.63

Source: Exh. No. RLC-9 in 1985 dollars.

118. LaCapra indicated that these costs include (1) the service drop; (2) the meter; and (3) associated general expenses including customer service and information accounts (Tr. p. 4241).

119. With several exceptions, Power holds that LaCapra has correctly taken a basic customer cost approach (Exh. No. 39, p. 66).

120. Power, however, states that customer service, information and sales accounts do not vary with the number of customers. Specifically, Power suggests that customer information costs should be re-classified as energy-related. Power also holds that "other distribution expenses" do not vary with the number of customers.

121. The Commission finds the development of precise customer costs problematic. The MPC and intervenors will have to empirically substantiate their respective claims in a later electric docket. For purposes of this docket, LaCapra's analysis is accepted.

122. The Commission would note Power's suggestion that a causal relation exists between customer information costs and energy use is weak: customer information involves the printing and mailing of information; surely these costs vary by the number of customers. The Commission would also note that, while Power claims the other customer related service and sales account costs, and distribution expenses do not vary by customer, the record does not indicate what these costs do vary with. In fact, Ramsey pricing principles would argue for recovering non-energy costs via the customer charge.

<u>Cost of Service: Other Issues</u>

123. <u>Line and Peak Losses</u>. In the process of transmitting power from the Company's generation facilities to customer's meters, both energy and peak losses occur. The amount of loss varies with the voltage level of service.

124. From LaCapra’s testimony it is clear the Company adopts marginal (as opposed to average) energy line loss adjustments (Exh. RLC-4, p. 1 and Tr. pp. 4072, 4073). It is not clear if LaCapra included peak losses in his marginal cost study; however, such losses are evident from the Company's work papers.

125. Power, on the other hand, has not taken a position on such losses:

> . . . The extent to which marginal line losses should enter into the calculation of marginal costs is something that I have not dealt with in my testimony, and I don't think I'm prepared quickly to respond to. (Tr. p. 4920).

126. The Commission finds that marginal energy line losses should be included as well as the Company's peak loss estimates as follows:

Energy and Peak Losses (%)[3]

Voltage Level	Energy	Peak
Transmission	13.36	9.11
Primary	15.96	11.61
Secondary	20.34	14.80

127. The above energy losses should be applied to the marginal energy unit cost results from the Base-Peak calculation. The peak losses should be applied to the generation, transmission, and distribution-related unit demand costs

128. Demand Allocators: Generation and Transmission. In a marginal cost of service study costs classified as demand related must be allocated to seasons and classes. Different procedures have evolved for allocating generation and transmission (G and T) demand costs than for distribution demand costs. The following describes how the former demand costs should be allocated.

129. LaCapra developed and used relative seasonal loss-of-load probabilities for purposes of allocating G and T demand costs to seasons (see Supplemental Workpapers, Rating Period Selection, p. 9 of 10 as summarized in Statement L, Appendix A, Peaker Marginal Costs, p. 4 of 6).

130. Next, LaCapra uses different allocators to allocate seasonal demand costs to classes. For the winter season, a single coincident peak (CP)[4] allocation is used; an average of monthly

[3]Source: Marginal energy losses are from Exh. No. RLC-4. Peak losses are from MPC's Supplemental Workpapers, System Energy Balance, page 9 of 10. The peak losses are proxies with primary associated with the missile sites, secondary associated with residential and transmission associated with industrial contract customers.

coincident peaks is used in the summer season (see Supplemental Workpapers, Normalized TDAC, p. 28 of 86 and Tr. pp. 4859-4860).

131. Wilson cited four alternative methods of allocating classified G and T demand costs to classes including a single CP, 12CP, a loss-of-load hour (LOLH) and a loss-of-load-probability (LOLP) methods (see Exh. No. 63, pp. 77-88).

132. Wilson argued that his LOLP procedure may be preferred to a simple LOLH because the simple LOLH only recognizes relative differences when, in fact, absolute loss of load probabilities in each season are also important.

133. LaCapra rebutted Wilson's proposed use of the LOLP:

Q. Dr. Wilson, in his testimony, has proposed two alternatives to your approach for loss of load. Are you familiar with those?

A. One of them comes to mind, which is the weighted loss-of-load factor, or loss-of-load hours. I'm not sure of the other one. Is that a straight loss-of-load probability?

Q. Yes.

A. Yes. Okay.

Q. Could you explain the relative disadvantages and the advantages of your approach and Dr. Wilson's two approaches?

A. Yes. The straight loss-of-load probability, as I recall, was quite similar to the loss-of-load hours approach that I used. The relative loss-of-load probability is significantly different, and I am going to use a generic formula and hope that this is the one that Dr. Wilson used. The relative loss-of-load probability looks at the value of 1 over 1, minus the quantity 1 over the loss-of-load hours. What this does is it

---

[4]Coincident peak refers to the system coincident peak. A coincident peak allocator allocates to a class a percentage of total demand costs equal to the same class' contribution of the system peak.

> tends to iron out the small differences in that at one point we may have a loss of load probability of triple zero one, and at another point we may have one of triple zero two, and the advocates would say, "Well, even though one is double the other, they're both so small that we cannot have relatively double allocation to one period versus another because on an absolute value, they're both small," and there is a logic to this argument.
>
> Where the problem comes in is if you apply that formula, you come into real appreciable differences and still not recognize them, because in any system that's designed to meet its load, the relative loss of load is always going to be small or else it wouldn't be a very well-designed system. Now to the extent that we may have 50 or 60 or 100 loss-of-load hours in a four-month winter period and 20 or 10 or 5, say, in an eight-month summer period, using a relative loss of load would wash out this difference considerably. To a planner, having 80 or 100 loss-of-load hours in a period is quite significant as compared to having 10. So the primary disadvantage of the relative value is while it does take care of the fact that there can be relatively small absolute differences, without wanting to magnify these and say both of them are relatively insignificant, it will have the problem, on the other end, that it could mask significant differences in loss-of-load hours as well. (Tr. pp. 4074, 4075).

134. Wilson also claimed that Power and Schoenbeck (who also endorses LaCapra's loss-of-load probability allocation) used incorrect loss-of-load data.

135. The Commission finds LaCapra's seasonal class allocation of G and T demand costs appropriate. Power also uses LaCapra's results in his allocation of G and T demand costs (see Exh. No. 39, Table I). The Commission finds Wilson's allegation incorrect. If one refers to the above referenced MPC workpapers, it is clear that LaCapra, and consequently Power and Schoenbeck, did not use loss-of-load data from a single month in each season.

136. The Commission would point out that the seasonal loss of load probabilities in the instant docket changed considerably from those in Docket No. 80.4.2. In the latter docket a 60 percent winter/40 percent summer split was used. In the current docket the split is on the order of 87/13 for the winter/summer seasons respectively. This result stems, in part, from changes in load forecasts as well as the resource mix (Tr. pp. 3632, 3633). In addition, it is clear from the Company's Statement (Statement L, Appendix A, p. 4 of 6) that the relative seasonal loss of load hour

percentages remain fairly constant through year 2005. It is the Commission's finding that the current results are more in line with relative loss-of-load study results in the northwest.

137. Demand Allocators Distribution. LaCapra used different noncoincident peak (NCP) methods to allocate distribution demand costs to classes. For primary voltage level demand he used a class NCP approach; for secondary voltage level demand he used a sum of NCP peaks of individual customers -- the sum of maximum customer demands (see Exh. No. 39, p. 67 and Tr. pp. 4237-4239). LaCapra's reasoning is that there is a different level of customer diversity at the two voltage levels.

138. Power disagrees with LaCapra's allocation of secondary voltage demand costs, noting that this allocation assumes . . . "all customers in a class impose their individual peak demands simultaneously and that the secondary distribution system is built to meet this simultaneous peak" (Exh. No. 39, p. 67). Power further notes that this assumption is unreasonable.

139. In the hearing LaCapra defended his allocation procedure for secondary voltage level demand:

> The secondary facilities were allocated on the basis of the sum of the noncoincident peaks of individual customers. Distribution facilities, line transformers, secondary services are sized primarily with very little consideration of diversity in that a particular line transformer is likely to be sized pretty much on the anticipated sum of the loads of the various installations that it is serving, so there is a differing level of diversity at the secondary system than there is back at the substation transformer. So to this extent, noncoincident peaks were used in both cases. However, class noncoincident peaks were used at the primary level and just some of maximum demands were used at the secondary level. (Tr. pp. 4237, 4238).

140. The Commission finds Power's argument convincing. Unless the secondary voltage level distribution is gold plated, a simple NCP allocation, as used with primary voltage demand, is appropriate: that is, if the sum of maximum customer demands are a proper allocator, then the system is gold plated.

141. Cost Periods: Seasons and Time-of-Day. The determination of periods having different costs is important so that customers consuming electric power in the various cost periods receive price signals indicative of the costs they impose on the utility system. The MPC and

intervenors in this docket suggested different cost periods. In Docket No. 80.4.2 (Order No. 4714d, Finding of Fact 113) the Commission tariffed seasonally differentiated demand and energy rates on the basis of concomitant variations in costs.

142. The MPC analyzed seasonal and daily variations in costs using marginal running costs (system lambda) and loss-of-load data. Based on this analysis LaCapra determined a significant difference in seasonal costs only (see MPC Exh. No. 2, p. RLC-13 and Exh. RLC-11). On this basis a winter season of November to February was established (the MPC's tariffs indicate November 21 through March 20 inclusive).

143. The MCC also analyzed MPC's time varying costs (see Exh. No. 63, pp. 62-64). Wilson determined that load patterns differ by season and by time of the day. Wilson found that two time-of-day periods in each of two seasons are justified. The seasonal periods are the same as LaCapra's. In addition, the hours from 7:00 a. m. to 9:00 p. m. on weekdays should constitute the peak period for purposes of determining class cost responsibilities. Unlike LaCapra, who used statistical analyses to determine the extent to which costs vary by time, Wilson's mode of analysis was visual inspection (Tr. p. 4576).

144. In contrast to Wilson's and LaCapra's findings, Power is strongly opposed to time-of-day rates [since rates should follow costs Dr. Power's position will be presented at this point and once more in the discussion on rate design]. Power's rebuttal arguments against time-of-day rates are as follows:

> 1. . . . There is little gained by shifting electric consumption from one period to another during the day.;
> 2. TOD rates are not likely to encourage conservation.;
> 3. The danger of TOD pricing is that it is promotional.;
> 4. ... very low off peak electric rates could encourage the development of totally new loads such as electric vehicles.
> and
> 5. TOD pricing with significant off peak price reductions also will undercut solar, insulation, and other alternative energy investments.
> (see Exh. No. 40, pp. 33-38).

145. In the hearing Power's position was expanded to include seasonal rate differentials as well as a distinction between energy and capacity:

Q. Do the energy costs that you show, you develop, and you refer to reflect the difference between operating costs of periods of relatively high load or peak periods and different costs -- energy costs for other periods?

A. In general, my analysis has not attempted a time differentiation of rates. To the extent that it was possible to adopt Mr. LaCapra's time-differentiated costs, I did so. The intent of my testimony was to provide an explanation of how long-run incremental costs should be calculated, not to go on and discuss how one would move to time-of-use rates if one was interested in doing so.

Q. Is that because you don't believe in the context of this case that time-of-use rates are significant -- a significant consideration?

A. I think the evidence indicates that there is a relatively small but significant difference by seasons currently, but that by time of day, there is not a significant difference.

Q. Well, I go to your Table H, Dr. Power, and I see there that you have -- there is a differentiation by season under No. 2 labeled, "Marginal Capacity Costs."

A. Yes.

Q. You have a winter cost of $57 and a summer cost of $10 a kilowatt, which appear to me to be a significant difference. Yet when I look under No. 1, the energy charge, you don't differentiate between seasons.

A. Yes.

Q. You differentiate for one; why do you choose not to differentiate for the other?

A. Because a base-load facility is built to serve customers at all times of the year, and for that reason, long-run incremental costs associated with that base-load facility should be reflected at any time that that facility's being used. (Tr. pp. 4855-4856).

146. Upon further cross on this subject Power states:

Q. With respect to your earlier testimony this morning, when you were discussing seasonal rates and the fact that thermal was used on the

> margin in both summer and winter; therefore, you wouldn't warrant in your mind a seasonal rate.
>
> Does that badly paraphrase what you said earlier?
>
> A. No. I support seasonal rates to reflect difference in loss-of-load probability and capacity component, the capacity. What was at issue this morning was the energy rates. Would I seasonally differentiate the long, run incremental costs of energy? And my response is that now I wouldn't. If one could show that there are seasons of the year during which consumption growth would not lead to the justification of building a base-load plant or moving up the construction of base-load plant, then I would support a lower seasonal energy cost. I don't think that's currently the case. (Tr. pp. 4991, 4992).

147. Based on the Base-Peak costing approach the Commission has adopted, there appears no need in differentiating energy costs by season or by time-of-day. In fact, Power argued that there is no reason to differentiate his energy costs by season or otherwise (Tr. pp. 4856,4992). Capacity costs are another issue, however.

148. The Commission earlier indicated its preference for allocating G and T-related demand costs to seasons. Implicit in this finding is that certain costs indeed vary by season and the allocation of costs to seasons should so be reflected. To this end, the Commission adopts the seasonal periods proposed by LaCapra and Wilson. At the same time the Commission takes note of Lively's concern that there exists statistical evidence in support of a sharper seasonal definition then recommended by the MPC and MCC (see Exh. No. 70, p. 11). However, the Commission finds that a move towards a sharper seasonal definition than currently exists should be done gradually. To this end the MCC's and MPC's Findings are reasonable.

149. The Commission does not agree with Lively's allegation that the wrong data was used in the development of costing periods. Both LaCapra's statistical analysis and Wilson's visual inspection came to the same conclusion regarding the seasonal costing periods; that is, all roads lead to Rome.

150. Regarding the development of TOD costing periods the Commission finds the record -- testimony and data -- does not support TOD differentiated demand costs.

151. <u>Cycle Billing, Industrial Loads and Coincidence Factors</u>. Lively and Schoenbeck raised a number of concerns with LaCapra's data normalization including: (1) coincident demands

in excess of maximum billing demand; (2) double counting of Stauffer's load; (3) over-estimating Stauffer's load factor and peak kw; and (4) coincidence factors for Stauffer and Golden Sunlight Mine. These concerns are addressed in turn.

152. First, regarding the concern that MPC has proposed coincidence demands in excess of maximum demands, LaCapra's rebuttal testimony (MPC Exh. No. 3, p. RLC-20) points out that the apparent contradiction is eliminated if the right data is compared. For example, ". . .the February peak should be compared to the March billing" (ibid, p. RLC-20). Schoenbeck acknowledged the lag problem in hearing (Tr. 9154).

153. LaCapra's data was also criticized for overstating the normalized Stauffer load in certain months. LaCapra concedes this error was made and should be corrected (Exh. No. 3, p. RLC-17).

154. In another area, Schoenbeck alleges MPC incorrectly assumed a 94.6 percent load factor for Stauffer, stating 70 percent is reasonable (Exh. No. 56, p. 9).

155. The Commission finds merit in Schoenbeck's allegation, which is supported by a data response to the Commission staff. From this response it is clear that Stauffer's monthly load factor for the period October 1982 to October 1983 never exceeded 76.7 percent (see Drazen Brubecker Data Response No. 30A to the Commission staff). It is also clear from Lekashman's testimony that normal operation at Stauffer is two furnace operation (Tr. p. 3766).

156. As a solution to this problem the Commission finds that the correct load factor should equal the higher of 70 percent or Stauffer's average load factor for two furnace operations during the time Stauffer has been a MPC customer.

157. Both Schoenbeck and Lively recommended alternative coincidence factors be used for Stauffer and Golden Sunlight. Schoenbeck recommends that historical test period coincidence factors be applied to the normalized billing demands of Champion Packaging and Ideal Cement; Schoenbeck recommends constant coincidence factors of 0.8661 and 0.9423 for Stauffer and Golden Sunlight (Exh. No. 56, p. 8).

158. Lively developed coincidence demands for Stauffer and Golden Sunlight using the contract industrials' coincidence and maximum demand data. (Exh. No. 70, p. 27).

159. LaCapra's rebuttal summarized MPC's and intervenors' positions on coincidence factors as follows (Exh. No. 3, pp. RLC-18, 19):

	Coincidence Factor (%)		
	MPC	Schoenbeck	Lively
Stauffer	0.901-0.941	0.8661	0.762
Golden Sunlight	0.862-0.924	0.9423	0.762-0.892

160. The Commission finds this area to be problematic. First, it is not clear from Lively's and Schoenbeck's analysis whether the witnesses assumed two-furnace operation. As indicated earlier, according to Lekashman two-furnace operation is normal. LaCapra on the other hand appears to have correctly assumed two-furnace operation (Tr. p. 3520). Consequently, the Commission accepts LaCapra's coincidence factors. It is also unclear whether the different coincidence factors stem from Schoenbeck's and Lively's failure to account for the lag difference discussed in Finding No. 152. The Commission would note that the various parties' results are not that divergent. Also, LaCapra's testimony clearly indicates his analysis captures the seasonal range in coincidence factors (Tr. pp. 4244, 4245).

161. Quality of Load Data. Yankel, on behalf of Montana Irrigators, filed the following criticisms of the MPC's load data:

1. The residential load research data is not representative of the test year data used for the other customer classes;
2. The irrigation load research data was not collected in a manner that would insure that its accuracy would live up to its design accuracy;
3. As opposed to billing data of the other classes, the actual billing data for the irrigation class was not found to be suitable by MPC for use in this case and as a result the Company's allocations to this class are based strictly on the results of a few sample customers. (Exh. No. 18, p. 29).

162. In hearing, Yankel indicated that MPC should have normalized load data by hour of the day. (Tr. pp. 5178-5180).

163. The Commission finds no merit in Yankel's claims of faulty load data. As admitted in the hearing, Yankel has no idea about the quality of load data on which the current rates are based:

Q. Mr. Yankel, on (sic) both this docket and in Docket 80.4.2, you found serious problems with the data that was used by various witnesses. In making those criticisms, did you make any comparison between the information available in 80.4.2 as opposed to the information available in the prior electric case that the then-existing and, to some degree, still-existing rates were based on?

A. I did not make a specific review, but I did review it in general. I did feel that the data was better this time than it was previous, especially for the irrigation class.

Q. What I'd specifically like to address first is the quality of data between the information available in 80.4.2 and the data that was available in setting the rate structure that existed prior to 80.4.2 that the rates you were looking at then were based upon.

A. I did not look at the previous case. I would have really no idea. I would assume that the quality of data between the two cases would have been comparable just because the Company had not been that much into their own load research and whatnot. As I understand it, they did have some load research that took place in the later Seventies, a limited amount. A limited amount for the case that took place in 1980, if that was the year, I'm not sure, that began in 1980. (Tr. p. 5183).

164. Yankel apparently does not dispute the claim that load data is far superior to that used in the previous docket. Although not perfect, as information filed in rate cases seldom, if ever is, the Commission finds it more than adequate as a basis for determining rates. LaCapra fully and adequately addressed Yankel's criticisms. As indicated by the following cross-examination, LaCapra actually <u>oversampled</u> in the load study:

Q. ...and '82. Do you have any opinion about why that happened?

A. Well, this is basically a count of service accounts, and it apparently shows signals that there were less billable accounts in the '82 population.

Q. With respect to that load/resource data, you stated that there was an oversample built into the design of the study Why was that done?

A. Well, <u>oversampling</u> (emphasis added) is a common technique to account for at least three problems, the first being perimetric error, in that what we are looking to derive from a load research program is

> fundamentally demands, and in many classes we don't have demand data. That's what we're looking for, so we stratify according to another variable, forced power or kilowatt hour. This introduces what is called a perimetric error which requires an adjustment in sample size.
>
> Another is meter failure rates, especially in the infancy of a program, due to meter installations, and going up a learning curve in terms of the meter tests and the meter readings we will experience a certain failure rate, and we would likely oversample for that.
>
> And the third is what's called a cross-stratification in that it's essential to a load research program to maintain a certain relative proportion among the various strata. To the extent that an individual customer who is being sampled will move between one strata and another can cause the variance of the sample to be altered, so we would oversample to ensure that there was sufficient -- there is a sufficient population in each strata to maintain the confidence of the sample that we want to maintain.

Q. My memory of your testimony was that that overdesign compensated for the fact that there were not the number of meters being tracked that were originally planned for the load/resource study. Given the fact that that over design has to cover what you have just discussed, how does it also cover for the fact that there were not a sufficient number of meters according to the design criteria?

A. Well, I think part of the answer is frankly that we were fortunate in maintaining or running into very few of those problems in that period because ultimately we have a couple good check points on whether we've truly represented the universe. For the irrigation class as well as the residential class, these check points beared out well (Tr. pp. 4058,4059).

165. The Commission finds no merit in Yankel's counsel of perfection and adopts the MPC's data for purposes of cost-of-service and rate design.

166. Estimated Marginal Costs. The following table summarizes the Commission's estimated marginal costs for purposes of class cost of service revenue responsibility.

Table 1
Estimated Marginal Costs

Function/Voltage	Classification		
	Energy (¢/kwh)	Demand ($/month)	Customer ($/month)
Generation:			
Primary	4.007[1]	7.80[2]	
Secondary	4.158[1]	8.07[2]	
Transmission	3.917[1]	7.34[2]	
Transmission:			
Primary	0.097[3]	4.29[4]	
Secondary	0.100[3]	5.07[4]	
Transmission	0.094[3]	4.20[4]	
Distribution:			
Primary		7.00[5]	
Secondary		2.00[6]	
Customer Related:			
Class			
Residential			$ 3.13
General Electric			$ 4.99
Irrigation			$ 4.94
Electric Contract			$99.18

1 Baseload capital costs equal $182.25 plus $27.60 (Exh. No. 67). The combustion turbine cost equals $80.72. Production O&M equal 1.35¢/kwh. The costs are developed using 1985 dollars and a 70 percent capacity factor. The resulting energy costs were combined with marginal energy line losses per Finding of Fact No. 126 above. The assumed escalation rate is that of 7 percent as in Exh. No. 67; this figure will have to be changed per the findings of this order.

2 These generation-related demand costs assume an $80.72 cost per kw and the peak loss percents in Finding of Fact No. 126. A seasonal breakdown requires loss-of-load adjustments.

3 These transmission related energy costs were computed per Finding of Fact No. 111, and include voltage level energy losses.

4 These voltage level transmission related demand costs equal $3.85/kw/mo. ($46.16/kw divided by twelve), adjusted per the Company's peak losses. A seasonal breakdown requires a loss-of-load probability adjustment.

5 This figure equals $75.32/kw multiplied times the primary peak loss factor of 1.1161 and finally divided by twelve.

6 This figure equals $20.97/kw multiplied times the secondary loss factor of 1.148 and finally divided by twelve.

The above estimates approximate but are not precise unit cost estimates per the findings of fact in this order. The MPC must revise these estimates per this order.

167. Reconciliation. In Finding No. 12 above the Commission set forth the stages involved in a cost-of-service study (functionalizing, classifying and allocation to seasons and classes) .

168. The issue of revenue reconciliation occurs with each and every cost study. The cost studies reconcile revenues at different stages of their respective cost of service studies. LaCapra (TDAC), Olsen (CICO) and Wilson (MCC) reconcile functionalized costs. On the other hand Power (HRC) performs his reconciliation of class (allocated) revenue requirements -- which is the same as reconciling classified costs.

169. The Commission finds that the most equitable reconciliation of class marginal cost revenue requirements is Power's equi-proportional adjustment. This is the same approach proposed by Company witnesses in other electric rate cases (MDU Docket No. 83.9.68 and PP&L Docket No. 83.5.36).

Rate Design

170. The Commission finds reason in this docket to deviate from the historic practice of setting forth rate design decisions simultaneously with cost of service decisions. Without knowledge of each classes reconciled revenue requirement the Commission finds merit in postponing rate design decisions.

171. The Company is directed to increase all rates by a uniform percent to recover the increase in the final revenue requirement in this docket; the exception to this uniform percent shall be the irrigation class. This exception stems from the Commission's expectation that a reduction in class revenue requirement for the irrigators may result. Consequently; to increase rates on a short-term basis followed by a decrease makes no sense to the Commission. The Commission is less certain if any other class may receive a decrease in revenue responsibility.

172. In order that the Commission can analyze alternative rate designs the Company must submit with reconciled class revenue requirements [note the below direction to assume the consolidation of some classes] certain billing determinants for each customer class including:

1. appropriate seasonal kwh consumption; in the case of the residential class the total kwh consumption, for each season, should be broken

down to accommodate a possible inverted block rate structure with break-points at 100, 200, 300 and 400 kwh per month;

2. appropriate demand (kw and hp) billing determinants and

3. appropriate number of customers per class to accommodate a possible service charge.

173. For the General Electric class the above data requests should be provided in a manner to allow possible bifurcation of this class into two separate schedules, demand and non-demand metered. For the demand metered class the number of kw less than and greater than "1" through "10" kw should be provided so that consideration of the number of "no charge" kw may be reduced from the current 10 kw/mo level down to zero kw per month. Both voltage level aggregated (primary and secondary) and disaggregated data should be provided for this class as well as the irrigation and electric contract class.

174. The Company should assume that the missile sites, MAFB and the Electric Churchs are served on the General Electric tariff.

175. On the irrigation schedule a minimum seasonal bill ($/hp of contracted load or horse power bill) should be assumed.

176. On the Electric Contract tariff billing determinants must be provided for the minimum bill provision as well as the excess demand charge.

177. Billing determinants (e.g., kvar) for all other rate elements and rates (e.g., lighting maintenance rates) must be provided.

CONCLUSIONS OF LAW

1. All Findings of Fact are hereby incorporated as Conclusions of Law.

2. The Applicant, Montana Power Company, furnishes electric service to consumers in Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. §69-3-101, MCA.

3. The Montana Public Service Commission properly exercises jurisdiction over Montana Power Company's rate and operations. §69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

4. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this docket. §69-3-303, MCA, §69-3-104, MCA, and Title 2, Chapter 4, MCA.

5. The cost of service approved herein is just, reasonable, and not unjustly discriminatory. §69-3-330, MCA and §69-3-201, MCA.

ORDER

THE MONTANA PUBLIC SERVICE COMMISSION HEREBY ORDERS:

1. The Montana Power Company shall design class cost revenue responsibility to generate authorized revenues which are consistent with the Findings of Fact entered by the Commission in this Order.

2. The Montana Power Company shall submit working papers revealing, in detail, the structuring of unit costs and class revenue responsibilities. The working papers are to be filed by August 10, 1984.

3. The Montana Power Company shall file rate schedules which reflect an increase in annual electricity utility revenues of $4,106,915, on a uniform percentage increase for all customer classes except the Irrigator class.

These rate schedules will be interim schedules pending the final approval by the Montana Public Service Commission of the rate design that will be developed as a result of Order No. 5051d of this docket. When the approved rate design is developed, the Montana Power Company shall file final rate schedules in conformance with that design.

4. All other motions or objections made in the course of these proceedings which are consistent with the findings, conclusions, and decision made herein should be granted; those inconsistent should be denied.

DONE AND DATED this 3rd day of August, 1984 by a vote of 5-0.

BY ORDER OE THE MONTANA PUBLIC SERVICE COMMISSION.

THOMAS J. SCHNEIDER, Chairman

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

CLYDE JARVIS, Commissioner

DANNY OBERG, Commissioner

ATTEST:

Madeline L. Cottrill
Secretary

(SEAL)